DIRECT TESTIMONY OF
SCOTT ROBINSON
ON BEHALF OF
DOMINION ENERGY SOUTH CAROLINA, INC.
DOCKET NO. 2020-229-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Scott Robinson. I am an Associate Director in the Advanced Solutions group at Guidehouse, formerly Navigant Consulting, Inc. My business address is 1375 Walnut Street, Boulder, CO. Today, I will be filing testimony on behalf of Dominion Energy South Carolina, Inc. ("DESC").

Q. BRIEFLY STATE YOUR EDUCATION, BACKGROUND, AND EXPERIENCE.

A. I have Masters degrees from the University of Texas at Austin's Jackson School of Geoscience in the Energy and Earth Resources program, and the University of Texas at Austin's Lyndon B. Johnson School of Public Affairs. I have published multiple peer reviewed journal articles on modeling the adoption of distributed solar photovoltaics (PV).[1] For the last six years, I have worked in distributed energy resources, transportation electrification, and energy efficiency at Guidehouse. My clients include state and local governments, utilities, and utility regulatory agencies on topics related to the modeling and impact of technology adoption, including solar PV.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA (THE "COMMISSION")?

A. Yes, I testified before the commission as part of Docket No. 2019-182-E. Also, I have been published extensively in the area of distributed behind the meter solar PV adoption, and with Guidehouse, I have conducted distributed solar PV adoption forecasts in seven states, including a similar study for Dominion Energy filed with the Virginia State Corporation Commission.

Q. WHAT ARE YOUR RESPONSIBILITIES AT GUIDEHOUSE?

A. I focus on quantitative forecasting and simulation of distributed energy, alternative fuel vehicle, and energy efficiency technologies. I lead teams of modelers and am responsible for several of our flagship distributed energy resource

[1] Robinson, S. A., & Rai, V. (2015). Determinants of spatio-temporal patterns of energy technology adoption: An agent-based modeling approach. *Applied Energy*, *151*, 273-284; Rai, V., & Robinson, S. A. (2013). Effective information channels for reducing costs of environmentally-friendly technologies: evidence from residential PV markets. *Environmental Research Letters*, *8*(1), 014044; Rai, V., & Robinson, S. A. (2015). Agent-based modeling of energy technology adoption: Empirical integration of social, behavioral, economic, and environmental factors. *Environmental Modelling & Software*, *70*, 163-177.

adoption models including DSMSim™, VAST™, GRIP™, and ReSim™ which was used to develop the distributed solar forecast for DESC. My responsibilities include managing model feature integration, quality and version control, and model enhancement planning. I frequently fill the role of senior modeler, technical quality manager, subject matter expert, lead modeler, or quality control lead on projects.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN DOCKET NO. 2019-182-E.

A. I presented testimony on a range of solar PV adoption forecasts in DESC territory, and attached Exhibit No. __ (SR-1) which provides the detailed methods, results, and conclusions that form the basis for that testimony. In that report, I showed that solar PV would continue to grow in DESC territory under the existing NEM rates, but that this growth has slowed down in recent years despite available federal and state incentives--signaling market maturity. Under the current NEM rates, the slow sustained growth of the Residential Single Family sector was forecast to account for the majority of solar PV adoption under all scenarios. I noted that the sunset of the ITC was expected to have an outsized dampening impact on adoption due to the value of upfront incentives relative to long-term debt payments, and that the reversal of this sunset in the "Low Cost" scenario would yield a 2 – 2.5 times higher capacity additions from new installations. I noted that commercial and industrial is a more limited "niche" market in DESC territory, and that while the Small Commercial sector has higher potential for growth than those customers on demand-based rates, Small Commercial solar PV adoption can be challenging as these customers are typically hard to reach. Small Commercial customers have a lower willingness to adopt overall, and the market is close to the long-run market share. It is only under the "Low Cost" scenario that the ITC extension creates enough headroom for more rapid growth.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose is to sponsor testimony regarding (i) the customer economics of distributed or behind-the-meter rooftop solar PV adoption in DESC's service territory, (ii) the methodology and assumptions made by Guidehouse in the analysis of the customer economics of solar PV adoption under the proposed NEM tariff, and (iii) forecast customer adoption of solar PV under the proposed tariff.

Q. HAVE YOU INCLUDED ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes, I have included the solar forecast that I submitted in Docket No. 2019-182-E as Exhibit No. __ (SR-1).

Q. WHAT IS ACCOUNTED FOR IN THE CALCULATION OF CUSTOMER ECONOMICS THAT YOU PERFORMED IN THIS DOCKET?

A. This analysis I performed in this docket estimated three components of customer economics: the simple payback period, return on investment (RoI) and the customer bill ratio. All were calculated in Guidehouse's ReSim™ model. Key assumptions used in the model were:

- System size. Multiple system sizes were tested for each sector, ranging from 3 kw to 7 kW DC for Residential Single Family, and 12.5 kW to 16.5 kW for Small Commercial.
- Solar PV generation. System generation profiles were calculated using the National Renewable Energy Laboratory's System Advisor Model, using default configurations, weighted average azimuth, and typical meteorological year weather data from Columbia, SC. In the base scenario, systems were assumed to have a financial life of 20 years, with 0.5% annual degradation.[2] This is a conservative assumption, and Guidehouse conducted sensitivity analysis on longer system lifetimes of 25 years.
- Electric Rates. For each sector, Guidehouse characterized proposed rate components in terms of a base energy and demand, peak period energy and demand, tiers and tier thresholds, hourly time-of-use ("TOU") period definitions, fixed charges, and grid connection charges. The study also assumes DESC's future rates increase with inflation (assumed to be 1.9%) based on the Bureau of Labor Statistics 10-year average annual inflation estimate.[3]

[2] Degradation refers to decreasing energy output of the system over time due to oxidation, optical losses, and other factors.

[3] Bureau of Labor Statistics CPI Calculator, https://www.bls.gov/data/inflation_calculator.htm. Accessed 9/6/2020

- Incentives. There are three major incentives in South Carolina that impact the distributed solar PV forecast.
    - **South Carolina Tax Incentives**. Taxpayers can claim a credit of 25% of the costs (up to $35,000) associated with purchasing and installing a solar PV system. The maximum credit a SC taxpayer may take in any one tax year is $3,500 for each facility or 50% of the taxpayer's tax liability for that year, whichever is less. Unused credit, or credit that exceeds the annual cap, may be carried forward for 10 years.
    - **Federal Investment Tax Credit**. The ITC allows the taxpayer to deduct a percentage of the cost of the solar PV system from their federal taxes. The original amount of the ITC was 30% of the installed system price. The ITC declined to 26% in 2020. As currently written, and assuming no further policy action, the ITC will adjust to 22% in 2021. For 2022 and beyond, commercial customers will be able to deduct 10% while residential customers will have no credit. The analysis uses this current ITC sunset trajectory in the “Mid-Cost” and “High-Cost” scenarios. In the “Low-Cost” scenario, the Guidehouse assumes the ITC is extended in 2021 at 30% for all sectors.
    - **NEM**. DESC’s proposed solar choice tariffs (the “Solar Choice Tariffs”) would allow customers who own or lease distributed generation systems to be compensated for the generation that is

coincident with on-site load using at the same rate that the customer would be charged for consumption. NEM customers could sell excess energy produced by their system back to the grid at the avoided cost credit designated in the company's solar choice tariff.

- Financial assumptions. The discounted cash flow model built into ReSim™ used in this analysis can capture the customer economics of cash purchase, lease, PPA, and loan purchase models. This economic analysis looked at both cash purchase and loan purchase models. For the loan purchase, a loan structure of 100% debt (no money down from the customer) was used to calculate the customer bill ratio. The loan term was assumed to be equal to the system financial life, with a 5% interest rate. Annual electricity savings were calculated assuming DESC retail rates increase with the pace of inflation, estimated to be 1.9% per year. The customer discount rate used for incentive payments was 10% for commercial and industrial customers, and 20% for residential customers. This is a compromise value between theoretical "rational" values and those observed in discrete choice experiments.[4]

[4] The customer discount rate implied from decision making is higher than might be assumed by rational actor theory, which might peg the discount rate on long-run returns such as an index like the S&P 500 (~7%). Commercial customers are assumed to be closer to actual market returns. See for example Dubé, J. P., Hitsch, G. J., & Jindal, P. (2014). The joint identification of utility and discount functions from stated choice data: An application to durable goods adoption. Quantitative Marketing and Economics, 12(4), 331-377.

- **Simple payback**. For the simple payback period, undiscounted annual cash flows were calculated for cash purchased systems, including the upfront equipment and installation costs, annual incentive payments, operation and maintenance costs, and customer bill savings. The payback time is the number of years it take for the total debits (positive cashflow) to equal the total credits (cash outflow).
- **Return on investment**. RoI was calculated as the discount rate at which the Net Present Value (NPV) of all the undiscounted cash flows listed above is equal to zero. Like the payback period, this is calculated for cash-purchased systems.
- **Bill ratio**. The customer bill ratio is defined as the all-in customer annual bill after installing solar PV (electric bill, system loan costs, O&M, incentives), divided by the annual electric bill the customer would have had without installing solar PV. This is calculated for a system purchased with a 0-down loan arrangement. The bill ratio is calculated using electricity rates, system performance, and building load levelized over the lifetime of the system. This differentiates the bill ratio from the RoI and simple payback, since these are calculated using unlevelized rates for each year of system operation.

- Solar PV Price. Solar PV prices were modeled based on individual system components, direct labor, permitting, overhead, margin, sales and marketing, and balance of system costs. Residential system prices are expected to fall from between \$2.4 – \$2.9/Watt DC in 2020 to \$2.01 - \$2.5/Watt DC in 2030. Commercial and Industrial system prices are expected to fall from between \$1.52 – \$1.86/Watt DC in 2020 to \$1.26 - \$1.56/Watt DC in 2030.

Q. PLEASE DESCRIBE THE SCENARIOS MODELED IN DESC TERRITORY.

A. Guidehouse modeled multiple scenarios. First, in line with the Solar PV Forecast provided in Docket No. 2019-182-E, Guidehouse modeled three solar PV cost and policy scenarios. The “Low Cost” scenario uses a lower Solar PV cost trajectory and assumes that the ITC will be extended. The “Mid Cost” scenario uses the mid-range Solar PV cost trajectory, and assumes the ITC will be allowed to sunset in line with current policy. The “High Cost” scenario uses the higher solar PV cost trajectory and assumes the ITC will be allowed to sunset in line with current policy. Guidehouse also modeled three system size scenarios for each sector, and two solar PV lifetime scenarios: 20 years, and 25 years.

Q. DOES YOUR MODEL USE PAYBACK TO SIMULATE CUSTOMER DECISION MAKING AROUND SOLAR PV ADOPTION?

A. No. The payback period is not used to simulate customer decision making in the model. While simple and discounted payback period calculations are model outputs, ReSim™ uses the customer's bill ratio to estimate the relative cost or expense of installing solar PV. The bill ratio is defined as the "all-in" new monthly bill after installing solar PV, divided by the bill would have been without solar PV. Since the customer experiences varying bills throughout the system life, the bill ratio is calculated using levelized rates. This allows us to accurately consider financing models like loan, PPA, and lease arrangements where the upfront cost is not a good proxy for total system costs to the customer.

Q. WHAT IS THE BEST MEASUREMENT OF CUSTOMER ECONOMICS FOR SOLAR PV?

A. Unfortunately, there is no one answer since there are multiple purchase mechanisms available to customers. The payback period is simple and intuitive, but does not capture the time value of money and does not apply when there is no initial cash outlay, as is the case in 0-down loan arrangements and solar leases. Return-on-investment (RoI) is a good alternative to payback since it can be used to compare one investment against another, but fails for 0-down loan arrangements and solar leases. For these arrangements, a fully burdened bill ratio is the best measurement since it expresses the customer's relative gain or loss. Relative is important because we should take into account how much the customer paid for electricity before installing PV. This is the denominator in the bill ratio.

Q. WHAT IS THE PAYBACK PERIOD FOR NEM CUSTOMERS UNDER THE CURRENT NEM PROGRAM?

A. Although not required by Act 62, DESC studied the payback periods for existing customer-generation systems under the Current NEM Program to understand the impact on the solar markets from a future rate change. These payback periods are generally around 7 years with slight differences in the payback depending on size of system.

Q. HOW DO THE SOLAR CHOICE TARIFFS CHANGE OPTIMAL SYSTEM SIZES FOR THE CUSTOMER?

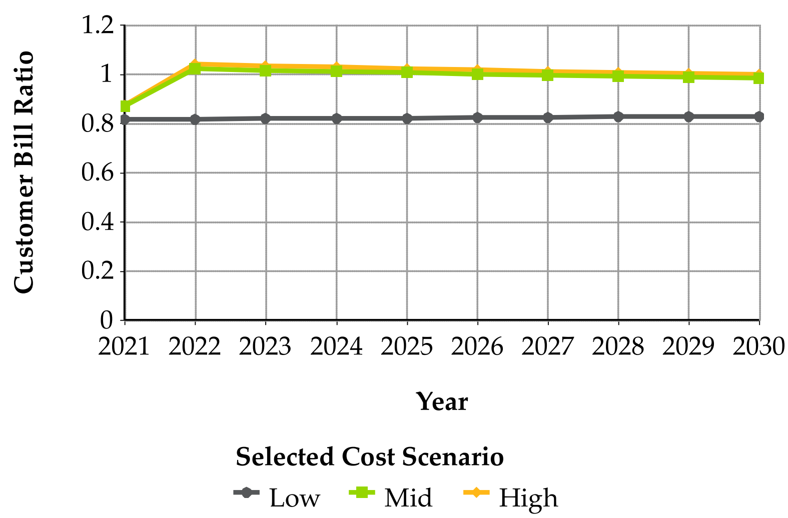
A. The current NEM program incentivized systems that aligned with the customer's total energy consumption over the whole year. Under the "Mid Cost" scenario these tend to be larger systems that would export of excess energy to the grid to make up for times when the system was not generating and the customer was consuming electricity. The new Solar Choice Tariffs incentivize smaller systems that are aligned with the customer's peak load. Guidehouse ran scenarios on the economics of different system sizes, and those that performed the best tended to be those that fit the customer's load shape. Under the "Low Cost" scenario larger systems tend to have improved economics since the ITC is calculated as a percentage of the total cost of the system.

Q. PLEASE BRIEFLY EXPLAIN THE FINDINGS AND CONCLUSIONS OF THE CUSTOMER ECONOMIC MODELING IN THIS DOCKET.

A. Key findings of the analysis include the following:

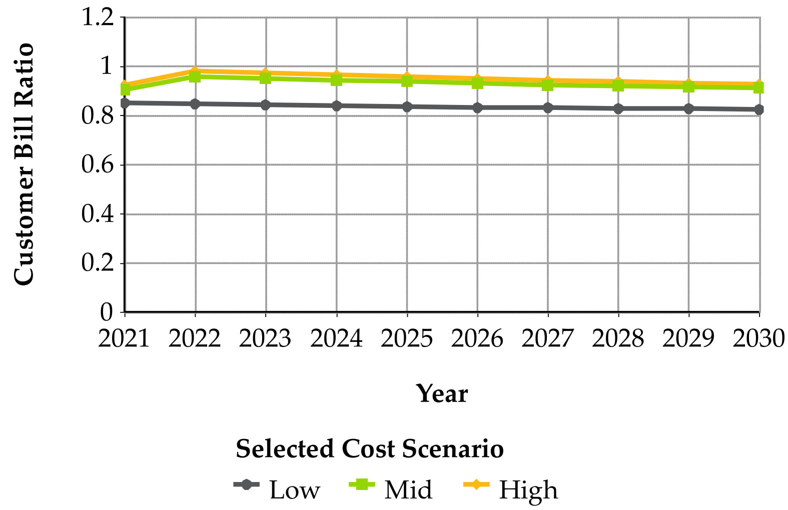
Customer bill ratios under the Solar Choice Tariffs for a 3 kW residential system are 0.81 for the "Low Cost", about 0.87 for both the "Mid Cost" and "High Cost" scenarios in 2021. Bill ratios over 1.0 can be interpreted as the customer paying a premium, while bill ratios under 1.0 can be interpreted as the customer saving money with the new system. Customer bill ratios are shown over the forecast period in Figure 1. Note that the spike in 2022 for the "Mid" and "High" scenarios are due to the ITC sunset.

Figure 1. Residential Customer Bill Ratios for Proposed NEM Subscription Rates



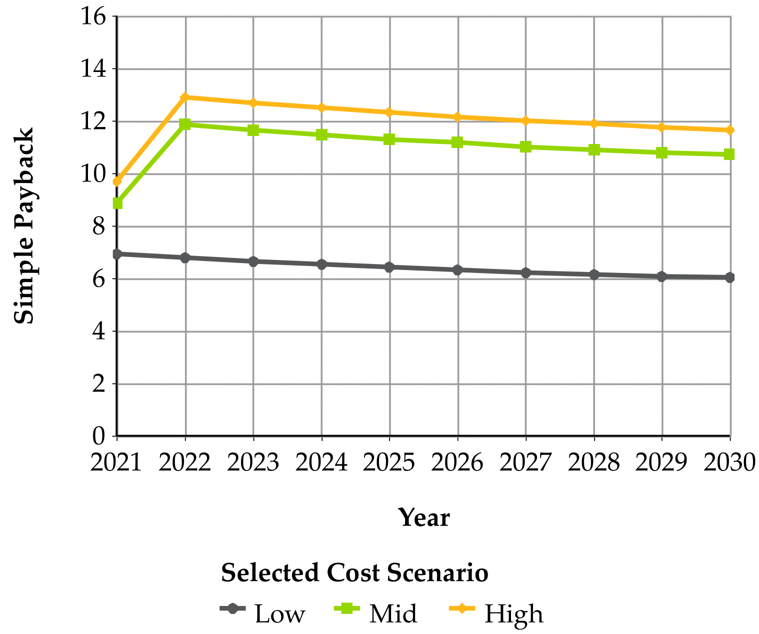
Customer bill ratios under the Solar Choice Tariffs for a 12.5 kW small commercial system are 0.85 for the "Low Cost", about 0.90 for the "Mid Cost" and 0.92 for the "High Cost" scenarios in 2021. These are shown over the forecast period in Figure 2.

Figure 2. Small Commercial Bill Ratios for the Proposed Solar Choice Tariffs



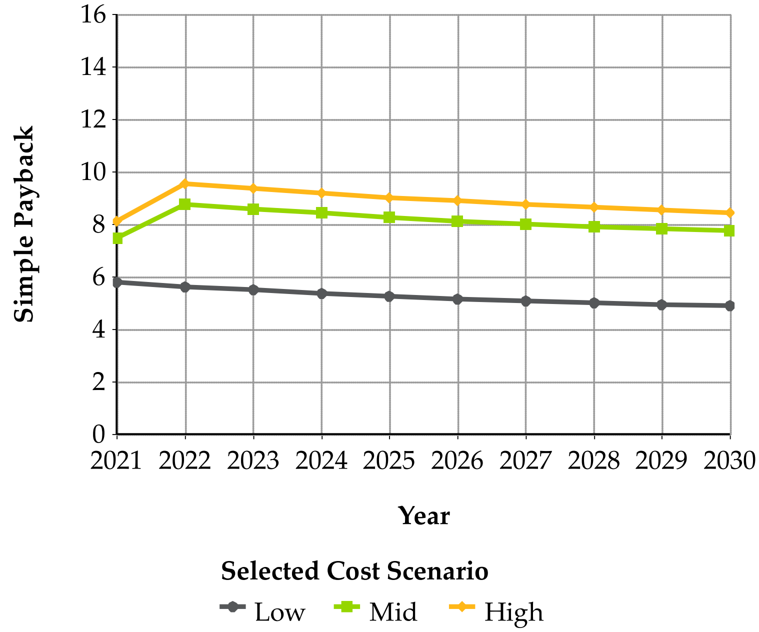
Simple payback periods under the Solar Choice Tariffs for a cash purchased 3 kW residential system in 2021 are 6.9 years in the "Low Cost" scenario, 8.9 years for the "Mid Cost" scenario, and 9.7 years for the "High Cost" scenario. The corresponding RoI is 16.9% in the "Low Cost" scenario, 11.8% in the "Mid Cost" scenario, and 10.3% in the "High Cost" scenario. Simple payback for these systems is shown over the forecast period in Figure 3.

Figure 3. Residential Solar Simple Payback Period for the Proposed Solar Choice Tariffs



Simple payback periods under the Solar Choice Tariffs for a cash purchased 12.5 kW small commercial system in 2021 are 5.8 years in the "Low Cost" scenario, 7.5 years for the "Mid Cost" scenario, and 8.1 years for the "High Cost" scenario. The corresponding RoI is 20.1% in the "Low Cost" scenario, 14.7% in the "Mid Cost" scenario, and 13.0% in the "High Cost" scenario. Simple Payback for these systems is shown over the forecast period in Figure 4.

Figure 4. Small Commercial Solar Simple Payback Period for the Proposed Solar Choice Tariffs



Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Guidehouse

DOCKET NO. 2020-229-E
EXHIBIT NO. __ (SR-1)

Dominion Energy South Carolina Solar PV Forecast

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Oct 07, 2020

Table of Contents

1. Executive Summary

Guidehouse developed a forecast for distributed rooftop solar photovoltaics (PV) in the Dominion Energy South Carolina (DESC) service territory for the period of 2020-2030 under multiple scenarios. The forecast used Guidehouse's ReSim™ model to estimate future installed capacity additions from Residential Single-Family, Small Commercial, Medium Commercial, Large Commercial, Other Commercial, and Industrial sector customers. In the "Mid-Cost" scenario we estimate a total of approximately 69 MW AC of behind-the-meter solar PV will be added in DESC territory, with 11.5 MW installed in commercial and industrial sectors and 57.5 MW installed in residential. Figure ES.1 shows forecasted cumulative distributed solar PV capacity in the "Mid-Cost" scenario.

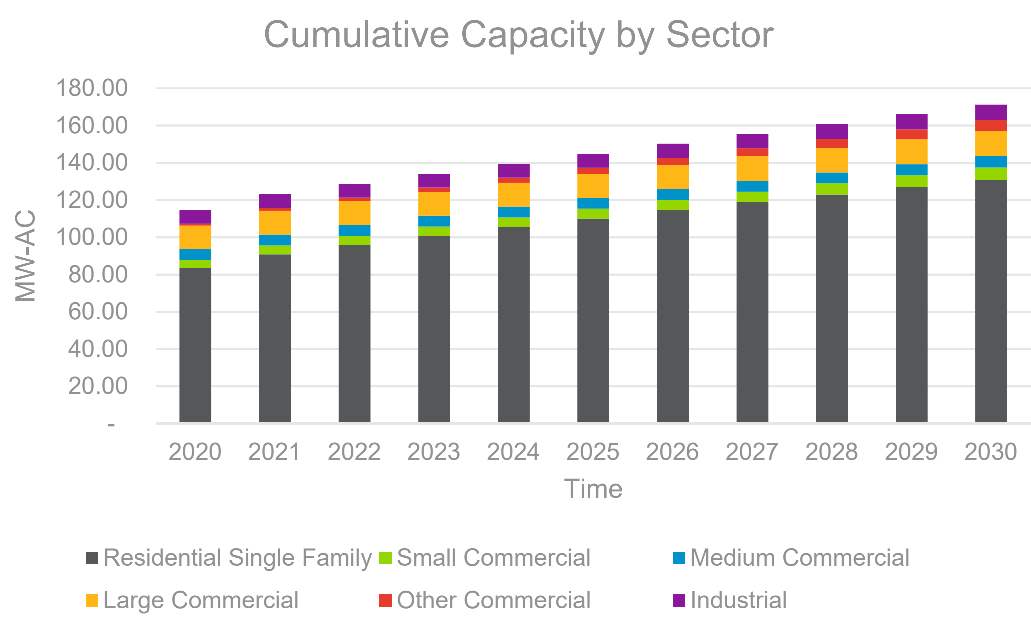

Figure ES.1. Cumulative Installed Capacity Forecast by Sector

The primary drivers of continued distributed solar PV growth are continuing cost declines for solar systems, new customer additions in the DESC service territory, and favorable policies such as Net Energy Metering tariffs, the South Carolina (SC) tax credit, and the federal Investment Tax Credit (ITC). If current policy stands, the ITC will expire altogether for residential customers, and ramp down from the 30% of the system cost in 2019 to 10% of system cost for commercial and industrial customers beginning in 2022. In recent years, the rate of distributed solar PV installation has slowed. Guidehouse forecasts that this trend will continue as the federal ITC tax incentives sunset in the upcoming years. Guidehouse developed an alternate "Low-Cost" scenario forecast that assumed an ITC extension and lower system costs. In this scenario, capacity additions from rooftop solar are roughly 2 times as high as in the "Mid-Cost" scenario.

2. Introduction

In this section we briefly describe the distributed rooftop solar PV market context in the state of South Carolina, and in DESC territory.

2.1 South Carolina Solar PV Market Context

Distributed solar photovoltaics (Solar PV) has experienced rapid growth in South Carolina due to decreasing module costs, a favorable policy environment (federal and state tax incentives, net energy metering), and broader customer familiarity with the technology. Since 2009, the introduction of third-party ownership (TPO) models initially led to solar growth in new market segments, but in recent years the trend has swung back to host-owned systems.[1] TPO contributed substantially to the maturation of the distributed solar PV market, and the popular loan financing models available today arose in part due to the popularity of these arrangements.

According to the Solar Energy Industry Association (SEIA) a cumulative ~1.5 GW-DC of solar PV have been installed in the state of South Carolina through Q2 2020, with another 1.7 GW-DC expected to be installed in the coming 5 years. On the state level, there was significant growth in the residential and non-residential sectors from 2015 through 2017, with growth flattening in 2018 through 2020. We observe similar trends in DESC's service territory, as shown in Figure 2 below.

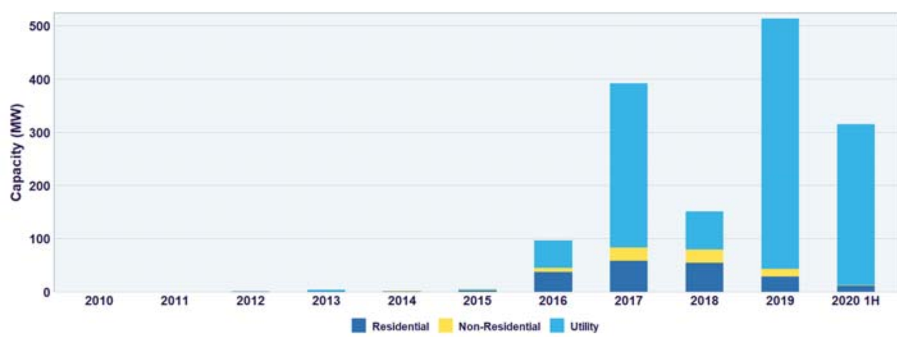

Figure 1. SEIA Data on Incremental South Carolina State Annual Solar Installations, 2010-2020 H1.[2]

In this report, Guidehouse presents a customer sector level forecast of distributed (behind-the-meter) solar PV system adoption in DESC territory. Customer adoption is driven by economic and non-economic factors with the primary drivers being installed system cost, electricity rates, and policy-driven state and federal tax incentives. System costs and rates are addressed in Section 3. The main policies driving adoption of distributed generation systems in South Carolina are described below.

- South Carolina Tax Incentives: Starting in 2006, South Carolina taxpayers are eligible to claim a credit of 25% of the costs (up to $35,000) associated with purchasing and

[1] Lawrence Berkeley National Laboratory (2019). Tracking the Sun Report. https://emp.lbl.gov/tracking-the-sun.
[2] SEIA, https://www.seia.org/state-solar-policy/south-carolina-solar

installing a solar PV system or other eligible technologies. The maximum credit a taxpayer may take in any one tax year is $3,500 for each facility or 50% of the taxpayer's tax liability for that taxable year, whichever is less. Unused credit, or credit that exceeds the annual cap, may be carried forward for 10 years.[3,4]

- Federal Investment Tax Credit. The federal Business Energy Investment Tax Credit (ITC) allows the taxpayer to deduct a percentage of the cost of installing a solar PV system from their federal taxes. Originally enacted in 2005 and set to expire in 2007, the ITC has been extended and amended several times, most recently in February 2018. The original amount the ITC allowed for deduction was 30% of the installed system price. However, in 2020 the ITC declined to 26% of system cost and will be further reduced to 22% of system costs for installations occurring in 2021. For 2022 and beyond, commercial customers will be able to deduct 10% of the cost for installed systems while residential customers will not be eligible for a federal tax credit.[5,6]

- Distributed Energy Resources Program Act of 2014 (Act 236). The act was designed to encourage renewable energy technology adoption, both utility-scale and behind-the meter installations. Act 236 had a large impact on the rooftop solar PV market in South Carolina. Among other things, Act 236:

    - Made solar PV leasing arrangements legal in SC, enabling third party ownership (TPO)

    - Mandated state-wide net energy metering until aggregate NEM capacity reached two percent of the previous five-year average of the utility's retail peak demand within the state[7]

    - Authorized rate recoverable DER programs. Incentives established by Duke[8] Energy and SCE&G[9] (Now DESC) led to rapid adoption of distributed solar PV

- The Energy Freedom Act (H. 3659). In February 2019, South Carolina legislators passed The Energy Freedom Act in a unanimous bipartisan vote. The act has many provisions, but some key provisions related to the customer classes in our analysis include:

    - Increasing customer protections

    - Removal of 2% NEM cap from Act 236

[3] http://solar.sc.gov/incentives

[4] https://programs.dsireusa.org/system/program/detail/1803

[5] https://www.seia.org/initiatives/solar-investment-tax-credit-itc

[6] https://programs.dsireusa.org/system/program/detail/658

[7] "Status Report on Distributed Energy resource and Net Energy Metering Implementation." South Carolina Office of Regulatory Staff. July 2017.

[8] $1/Watt upfront incentives

[9] Up to $0.04 per kWh generated for projects up to 20 kW

- Establishing full NEM credits for customers who qualify and apply for the NEM tariff through 6/1/2021
- Replacing the current NEM tariff with "solar choice metering tariffs" determined by the Public Service Commission beginning in 6/1/2021
- Adding "energy storage" to the customer-generator definition
- Removing caps on solar leasing[10]

2.2 Study Overview and DESC Context

DESC contracted with Guidehouse to develop behind-the-meter solar PV adoption forecast scenarios for residential and non-residential customers in its service territory. Our methodology and assumptions are presented in Section 3, results are presented in Section 0, and conclusions are presented in Section 5.

In DESC territory, NEM behind-the-meter solar PV grew rapidly from 2015 to 2018 and grew at a reduced rate from 2019-2020. To date, the distributed solar PV market has been led by residential installations, though commercial and industrial sectors have also experienced rapid growth, as shown in Figure 2. The rapid growth of the distributed market can be attributed in part to the establishment of incentives by DESC (then SCE&G) in response to Act 236 (See Section 2.1).

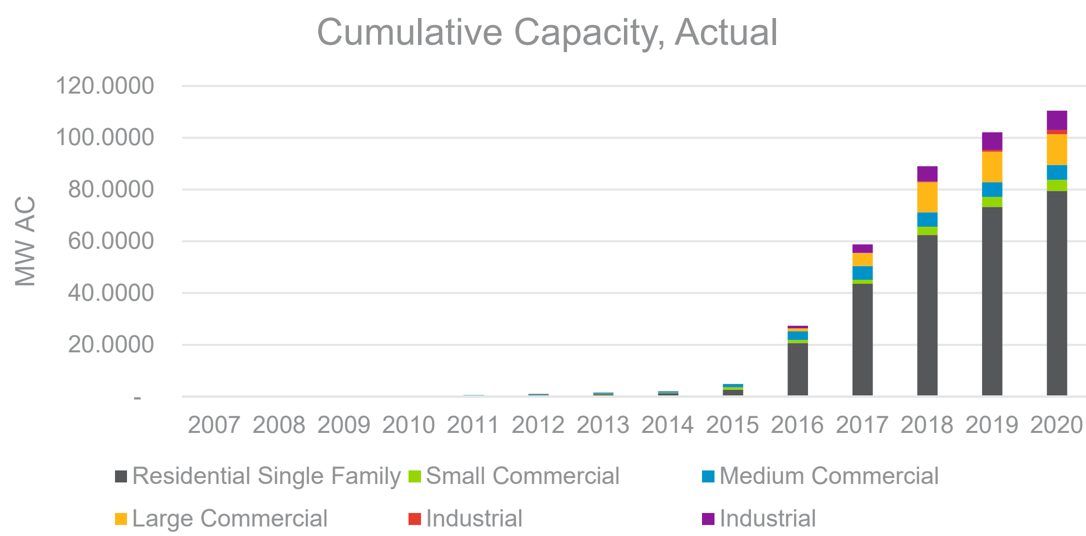

Figure 2. DESC Historical Installed Distributed Solar PV Capacity[11]

[10] http://www.energy.sc.gov/files/view/SC%20Energy%20Freedom%20Act_summary%2009.012.2019.pdf

[11] Note that Q4 of 2020 was extrapolated to allow the year to be included in this figure.

In addition to the statewide policy drivers summarized in Section 2.1, DESC's current NEM tariff developed as a result of SC Act 236 contributed to distributed solar growth in the company's territory. Specifically, DESC customers who own or lease qualifying distributed generation systems receive excess electricity credits at the full retail rate up to the full amount of the energy charges for the month.[12] Any unused excess energy credits are carried over to the next month at the full retail rate value until the credits are fully utilized or until year-end. Any remaining credits at year-end are compensated at the wholesale rate. This rate design provides NEM customers full retail rate level compensation for excess energy credits and has significantly improved the economics for installing solar systems.

[12] https://programs.dsireusa.org/system/program/detail/3041

3. Methods

Distributed solar PV adoption depends on economic, social, and behavioral factors. [13] To forecast the amount of distributed solar PV expected to be installed through 2030, Guidehouse used its ReSim™ model. The model uses a systems dynamics framework to explicitly account for the drivers (e.g. incentives, cost declines) and boundaries (e.g. information, costs, shading) to adoption, as shown in Figure 3. Adoption of solar PV is calculated using an enhanced Bass diffusion[14] framework, whereby coefficients on customer preference, and rate of information exchanged are calibrated to historical adoption data.

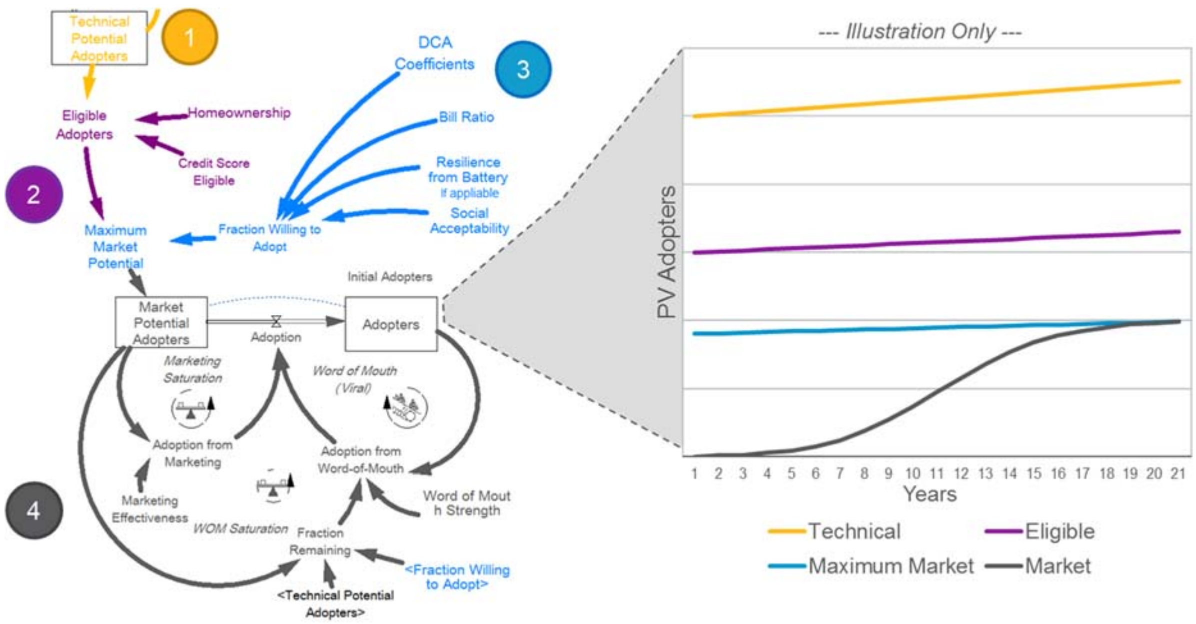

Figure 3. High-level Influence Diagram (left) and Corresponding Illustrative Output (right) of Guidehouse's ReSim™ Model.

3.1 Methods: Technical & Eligible Potential

In the ReSim™ model, Guidehouse estimates the Technical Potential for solar PV – the installed capacity that could be reached if all customers with adequate roof characteristics installed systems, regardless of their financial means, own/rent characteristics, willingness to pay, or familiarity with the technology. Technical potential is assessed instantaneously, such that each year is a snapshot in time.

Guidehouse determined the Technical potential for DESC territory using the formula in Figure 4.

Technical Potential = **# Customers** ✖ **Avg System Size (kW AC)** ✖ **Solar Access Factor**

Figure 4. Technical Potential Equation

[13] Robinson, S. A., & Rai, V. (2015). Determinants of spatio-temporal patterns of energy technology adoption: An agent-based modeling approach. *Applied Energy*, *151*, 273-284.

[14] Bass, Frank (1969). "A new product growth model for consumer durables." *Management Science 15 (5): p 215-227*

Guidehouse utilized DESC sector-level forecasts to determine the number of customers in each sector, sector forecasted load growth, and usage per customer (UPC). Average system size was calculated as a percentage of customer energy usage, with reference to DESC data on installed system sizes. Guidehouse assumes electricity generated from solar PV meets 75% of electricity usage for Residential Single-Family, Small Commercial, and Other Commercial, 50% of electricity usage for Medium Commercial, and 10% of electricity usage for Large Commercial and Industrial segments. This system sizing approach yielded system sizes comparable to those observed in DESC's historical interconnection data, but better suited to average customer sizes, rather than the early adopter population.

The percentage of customers with adequate roof characteristics in a population is called the Access Factor. Guidehouse determined the Access Factor for DESC's territory though analysis of National Renewable Energy Laboratory (NREL) data[15] as shown in Figure 5.

NREL Access Factors Methodology

- Lidar data for 128 cities was obtained from the Dept. of Homeland Security.
- Lidar & building footprint data was processed based on shading, tilt, and azimuth of each rooftop to determine rooftop suitability results.
  - **Shading:** Evaluated shading on March 21, June 21, September 21, December 21. Roof area that did not receive enough sunlight to produce 80% of the energy produced by an unshaded area were excluded.
  - **Tilt:** Determined tilt of each square meter of roof. All tilt values greater than 60 degrees were removed from the data set.
  - **Azimuth:** Assigned a roof tilt to each roof plane. All roof planes facing northwest through northeast were excluded.
  - **Minimum Roof Size:** Roof required to have at least 10 m^2 of area, a sufficient area to install at 1.5 kW system.
- A statistical model used to apply the results from the 128 cities to the remaining U.S. Results aggregated to determine total quantity of rooftop area suitable for PV systems at building, zip code, utility service territory, state and national levels.
- Calculate the installed PV capacity on the suitable roof area.
- Subdivided buildings into small, medium and large, evaluating trends.
- Simulated productivity of PV modules covering suitable roof area.

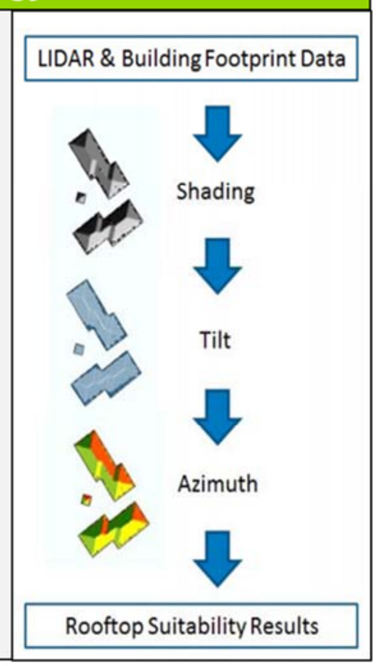

Figure 5. NREL Suitability Methodology for Rooftop Solar Photovoltaic Technical Potential in the United States

[15] Gagnon, P., Margolis, R., Melius, J., Phillips, C., & Elmore, R. (2016). *Rooftop solar photovoltaic technical potential in the united states. A detailed assessment* (No. NREL/TP-6A20-65298). National Renewable Energy Lab.(NREL), Golden, CO (United States).

Eligible Potential is the technical potential after accounting for owner occupancy and creditworthiness. Residential owner occupancy and income data are sourced from the U.S. Census[16,17] and commercial owner occupancy data is sourced from the Energy Information Administration's Commercial Building Energy Consumption Survey (CBECS).[18] Income data are used to estimate credit score, as credit score data were not directly available. No building rental information was available for industrial customers, and thus all were assumed to be owner-occupied.

3.2 Methods: Long Run Market Potential

The Long Run Market potential (also known as Maximum Market potential) is the Eligible potential after accounting for the customer economics of adoption, and the customers' price sensitivity. Thus, the Long Run Market Potential is a function of customer willingness to pay for a technology but does not account for customer technology awareness. We refer to this calculation as the long-run equilibrium market share when speaking in percentage terms.

The long-run equilibrium market share is assessed using a discrete choice formulation, where the market share for a given technology is a function of social and economic characteristics of the technology, plus any inherent preference (either positive or negative) for the technology, which is critical to solar PV adoption. Inherent preference, or the "technology specific" coefficient, captures non-economic factors such as green preference, hassle factor, installation concerns, resale issues, etc. The Long Run Market potential acts as a dynamic asymptote for the Market potential.

Customer economics are calculated through a discounted cash flow analysis of the cost of owning and operating the system through a zero-down loan arrangement[19], so that the monthly cost of the system can be levelized and compared against the monthly bill that the customer would have paid without the solar PV system. This is expressed as a ratio and fed into the discrete choice logit market share formulation. The discounted cash flow analysis accounts for customer-facing factors, such as component prices of the system, an inverter replacement in year 10, the remaining monthly electric bill, left over excess NEM credits, and incentives such as the federal ITC and the 25% South Carolina state tax credit.

Electric rates are also an important component of the customer economics of solar PV ownership. For each sector, Guidehouse characterized rate components directly from DESC's 2020 rate schedules in terms of a base energy and demand, peak period energy and demand,

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[16] US Census American Community Survey 2018 5-Year Estimates for South Carolina. Housing Occupancy Table. https://data.census.gov/cedsci/table?g=0400000US45&d=ACS%205-Year%20Estimates%20Data%20Profiles&tid=ACSDP5Y2018.DP04&hidePreview=true Accessed 9/3/2020

[17] US Census American Community Survey 2018 5-Year Estimates for South Carolina. Household Income by Mortgage Status. https://data.census.gov/cedsci/table?q=B25098&g=0400000US45&tid=ACSDT5Y2018.B25098&hidePreview=true Accessed 9/3/2020

[18] CBECS 2012 https://www.eia.gov/consumption/commercial/data/2012/ Accessed 9/3/2020

[19] Though some customers do purchase systems with cash upfront, these are a minority. The zero-down model is the best single approximation for loan and lease arrangements.

tiers and tier thresholds, hourly time-of-use (TOU) period definitions, and fixed charges. Sector-level weighted averages were developed for each of these components using the percentage of sector energy consumption associated with each electric rate. Future rates were assumed to increase only due to inflation (1.9%).[20]

System output was calculated in the National Renewable Energy Laboratory (NREL)'s System Advisor Model[21], using default options for module and inverter make/model, and typical meteorological year weather data from Columbia, SC, and a weighted average of different system azimuths (orientation). Orientation data was taken from national data from Lawrence Berkeley National Laboratory (LBNL), and suggests that approximately 57% of systems are south-facing, 17% are east-facing, 23% are west-facing, and 3% are north-facing.[22] North-facing systems were excluded from the Technical potential through the use of NREL's access factor methodology, but included in the weighted average system generation profile. This creates a slightly more conservative assessment of Technical potential but remains the best assessment of average solar generation without introducing the undue complexity of carrying an "orientation" index though the model. Customer load shapes from DESC allowed Guidehouse to calculate the energy flows from the system and net customer load for bill calculations.

3.3 Methods: Market Potential

Market Potential is the most accurate assessment of the future installed capacity and the focus of this report. It accounts for all the factors included in Technical, Eligible, and Maximum Market Potential, as well as the rate at which information diffuses in the market. Typically, though not always, this diffusion process will result in so-called "S-shaped" curves when viewed in cumulative terms due to positive feedback and balancing effects.[23] For solar PV, technology awareness is particularly important to potential adopters,[24] and can generate strong word of mouth effects. Guidehouse used an enhanced Bass diffusion formulation to simulate the flow of information to potential adopters (awareness). The model was calibrated to historical interconnection data provided by DESC. The calibration process is discussed in Section 3.5.

3.3.1 Market Potential Scenarios

Guidehouse conducted scenario analysis on market potential, varying system prices and policy levers. The "Mid-Cost" scenario acts as the base case. In this scenario, the ITC is allowed to sunset to 0% for residential, and 10% for commercial and industrial customers. In the "Low-Cost" scenario, Guidehouse used the lower system price forecast (see Section 3.4) to calculate the total cost of system to the customer, and set the federal ITC set back to 30% for all

[20] Bureau of Labor Statistics CPI https://www.bls.gov/data/inflation_calculator.htm,
August 2010 - August 2020. Accessed 9/3/2020

[21] Freeman, J. M., DiOrio, N. A., Blair, N. J., Neises, T. W., Wagner, M. J., Gilman, P., & Janzou, S. (2018). System Advisor Model (SAM) General Description (Version 2017.9. 5) (No. NREL/TP-6A20-70414). National Renewable Energy Lab.(NREL), Golden, CO (United States). https://sam.nrel.gov/

[22] Lawrence Berkeley National Laboratory (2019). Tracking the Sun Report. https://emp.lbl.gov/tracking-the-sun.

[23] Sterman, John D. Business Dynamics: Systems Thinking and Modeling for a Complex World. Irwin McGraw-Hill. 2000. p. 332

[24] Rai, V., & Robinson, S. (2013). Effective information channels for reducing costs of environmentally-friendly technologies: evidence from residential PV markets. *Environmental Research Letters*, *8*(1), *014044. https://iopscience.iop.org/article/10.1088/1748-9326/8/1/014044/meta*

customer sectors starting in 2021. The “High-Cost” scenario also assumes the same ITC policy assumption as the “Mid-Cost” scenario (ITC is allowed to sunset) but uses the higher solar PV cost forecast.

3.4 Solar PV Cost Forecast

Guidehouse developed a distributed solar PV system price forecast for residential and commercial & industrial (C&I) customers to inform the economics of adoption, and thus, the long run equilibrium market share. Guidehouse forecasted solar PV system prices using individual component forecasts accounting for all aspects of system price for residential and C&I customers. Our forecast views the installed costs from the perspective of the end buyer, taking into account system components, direct labor, permitting, overhead, margin, sales and marketing, and balance of system costs. We then benchmark our forecast with other third-party market views as well as industry experts[25]. There is a range of prices in the marketplace, and we attempt to capture this variability by developing three system cost forecast scenarios. The “Mid” case reflects what Guidehouse believes to be the most likely case with the “High” and “Low” cases showing a range of reasonable variability in the market.

The study assumes the price of solar PV will continue to decline for residential and C&I customers, largely driven by improvements in module efficiency that in turn impact other installed system costs. Historically, higher efficiency modules were more expensive to produce and captured a price premium relative to standard modules and therefore had a smaller market share. Manufacturers reduced costs largely by improvements in economies of scale, but over time as the industry matured incremental cost declines became more difficult to achieve. To continue reducing costs, the industry shifted focus and resources to improving the module technology and efficiency. Over the past few of years, manufacturers shifted to high efficiency modules by using technologies such as Passivated Emitter and Rear Contact (PERC) and bifacial modules. As the cost of higher efficiency modules declined, adoption and market share also increased. Variants of PREC technologies currently dominate the US market, especially the residential and C&I sectors. Moving forward increases in module efficiency are expected to continue as companies continue to invest in PERC and other technologies also seen in technology improvement roadmaps.[26]

The improvement in module efficiency reduces the number of modules needed to achieve the same nameplate capacity or system size. The smaller system footprint also impacts overall system installation costs such as hardware and labor. We expect improvements in module efficiency to continue and remain the key driver in decreasing installed system costs over the coming years. Our forecast residential and C&I forecast results are presented in Figure 6 and Figure 7 respectively, in nominal dollars/Watt, DC.

[25] PV Insights, National Renewable Energy Laboratory (NREL), Solar Energy Industries Association (SEIA),

[26] International Technology Roadmap for Photovoltaic (ITRPV), 2019 Results, Eleventh Edition

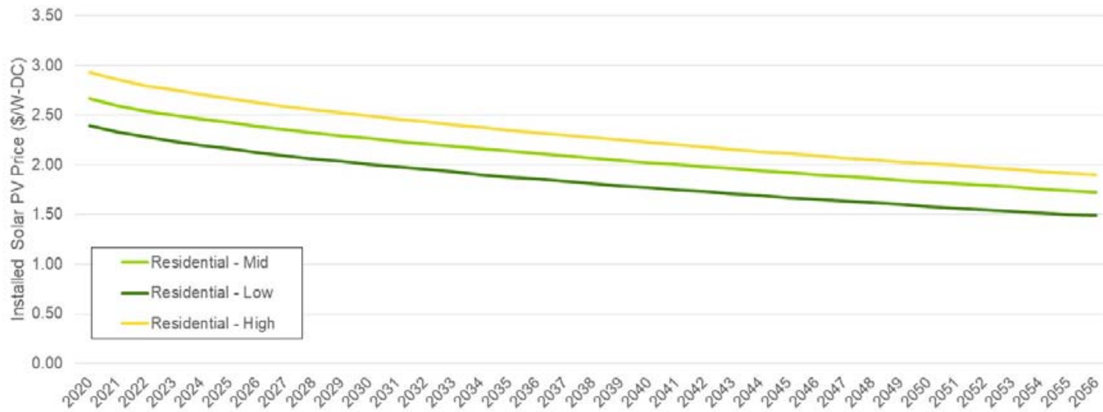

Figure 6. Installed Residential Solar PV System Price Forecast, 2020-2056

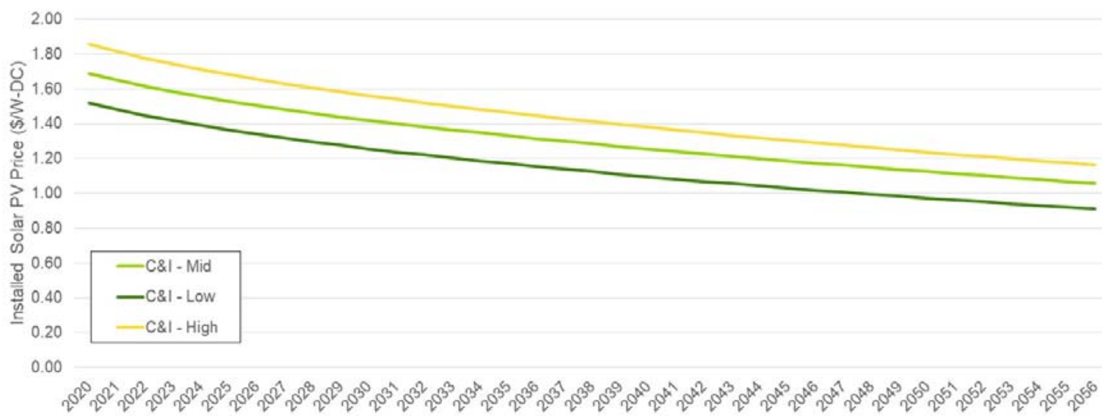

Figure 7. Installed C&I Solar PV System Price Forecast, 2020-2056

3.5 Calibration

Model calibration consists of generating simulated data to compare against actual adoption data during a training period in order to refine model parameters. This gives the model a strong empirical basis in the market conditions unique to the DESC territory. A subset of the historical data, the test set, is held back until after the coefficients have been estimated to avoid overfitting. The test set is used to gauge the out-of-sample fit of the model.

Calibration was conducted on DESC historical installed solar PV system data from 2016 – 2019, with 2015 as the backcast baseline year. The 2020 calendar year is held back as the test set. Guidehouse fit three parameters during calibration using a non-linear optimization engine: two Bass diffusion coefficients (the “word of mouth” and “marketing” parameters), and a “technology specific coefficient” in the logit formulation that adjusts for non-economic factors in customer preference. Summary fits for combined training and test data are shown in Figure 8. After fitting, the Root Mean Squared Error (RMSE) for the combined training and test data was 4.01, or 1%.

The out of sample accuracy on the test set was 91%. Sector level calibration results are shown in Figure 9.

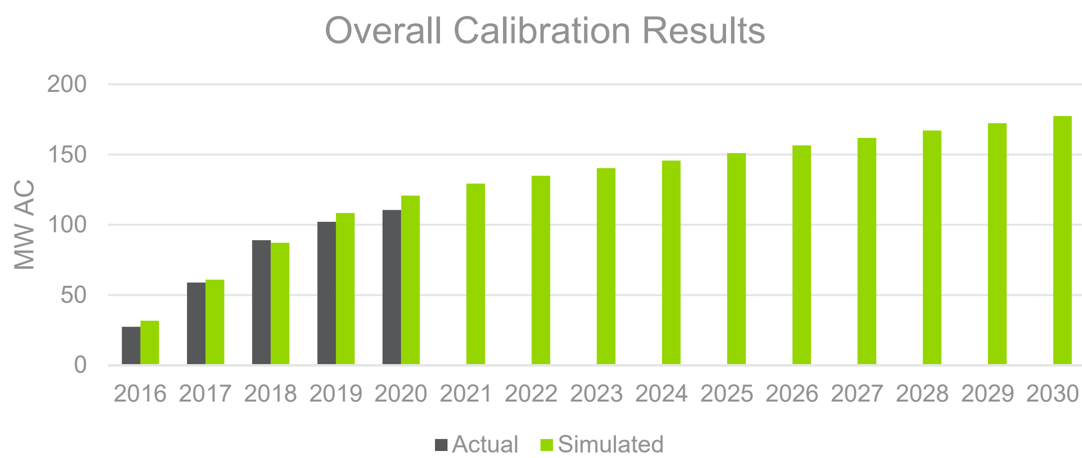

Figure 8. Sector Totaled Calibration Results

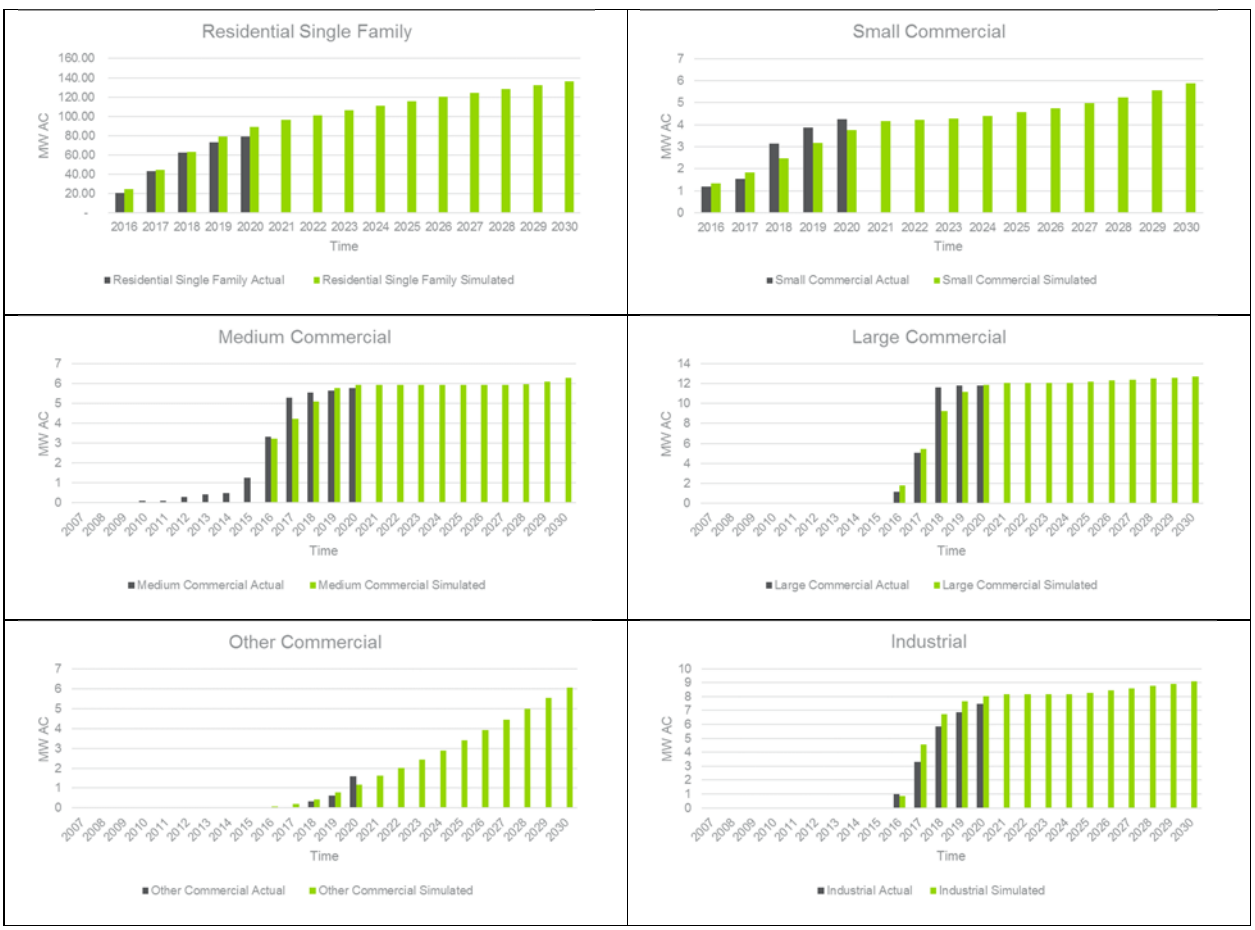

Figure 9 Sector Level Calibration Results

While calibration resulted in close alignment between the ReSim™ model results and actual adoption, it is worth noting a few discrepancies. For all sectors, market maturation appears to be occurring slightly more rapidly in the actual data than the model predicts. This can be seen for example in the Medium Commercial sector, which displayed rapid growth in 2016 and 2017, and then growth was more or less flat from 2017-2020. The model is able to approximate this result but shows at slower growth trend. The Other Commercial segment shows steeper growth in 2020 than predicted by the model, and thus it appears to suggest a steeper growth trend. However, this is due to the interconnection of two large systems (300 and 400 kW) in the same week, and the low magnitude of the total installed capacity.

4. Results

In this section, Technical, Eligible, Maximum Market, and Market potential are presented. In the Market Potential section (Section 4.3), we present scenario results by sector.

4.1 Technical & Eligible Potential

Technical potential is the amount of solar PV that could be technically installed, regardless of real-world market constraints, as described in Section 3. Although adoption at this level is unrealistic, it offers an upper bound to any analysis and constrains the stock by screening out unsuitable buildings based on important factors like shading, orientation, setbacks, and structural characteristics. Technical potential for DESC is increasing slowly over time with new construction. Overall Technical potential expected to reach over 2 GW AC in 2030 as shown in Figure 10. Technical potential is estimated to be evenly split between residential and non-residential (C&I) segments.

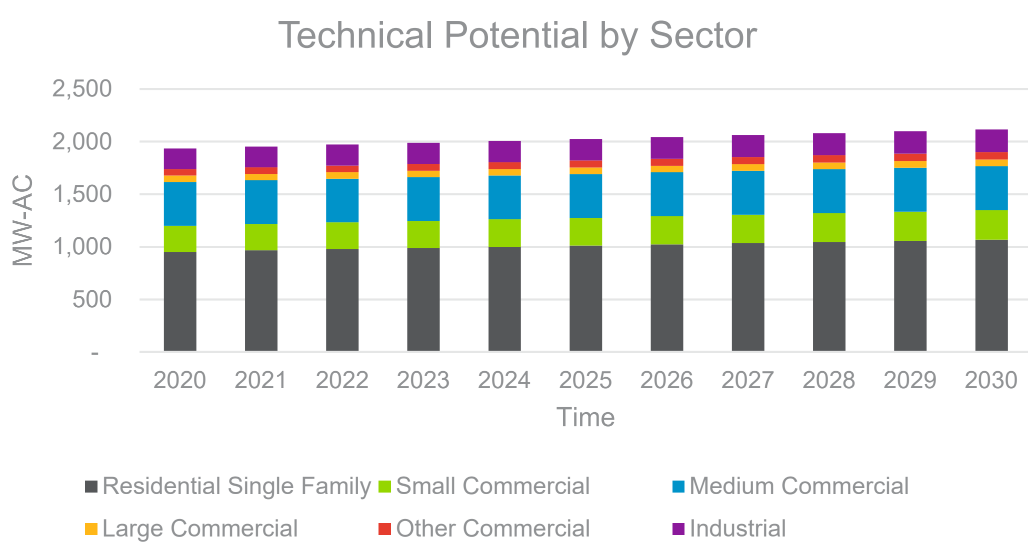

Figure 10. Solar PV Technical Potential in DESC

Eligible potential acts as a further constraint, accounting for non-technical characteristics that would practically prevent customers from adopting the technology. The most important eligibility constraint for solar PV is owner occupancy. Because this study did not consider community solar opportunities, renters were screened out of the Eligible potential population. Similarly, for residential, a portion of the population of homeowners was screened out due to credit score. Creditworthiness means suitability of the household to take out a loan though a bank, solar company, or other institution to finance the system. Eligible potential is shown in Figure 11. For Industrial, no eligibility constraints were enforced, and thus Eligible potential is equal to Technical potential.

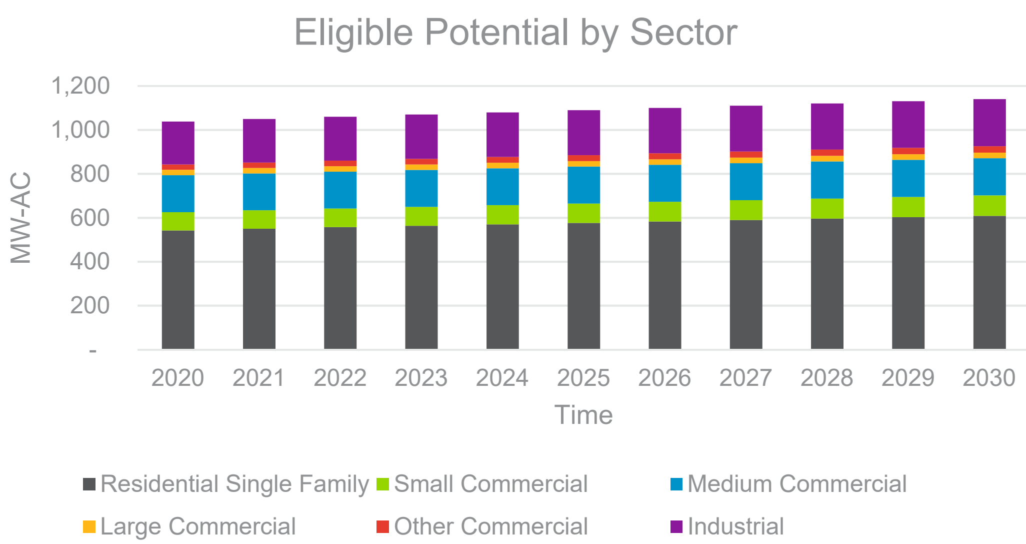

Figure 11. Distributed Solar PV Eligible Potential in DESC by Sector

4.2 Long Run (Maximum Market) Potential

The Maximum Market potential defines the long run equilibrium for the market forecast and represents the instantaneous potential possible given the populations full awareness or familiarity with the technology. For solar PV, this means awareness of attributes like ease of installation, project costs and financing options, incentives and benefits, and any non-economic attributes that the customer may value such as environmental benefits, or social signaling. See Section 3.2 for details.

Importantly, the Maximum Market Potential shows the market response to changes in the cost of solar discussed in Section 3.4 as well as the changes to incentives. Figure 12 shows that the Maximum Market potential decreases from 2020-2021 in the response to the ITC sunset over that same period in the “Mid-Cost” scenario. The impact is most pronounced in the Residential Single-Family sector. The general increasing trend in the Maximum Market potential from 2022-2030 shows the smaller effect of solar PV price declines. The relatively smaller impact of the price declines demonstrates the important of the ITC. Because the ITC benefit is delivered upfront in the next tax year, it is more valuable to customers due to the time value of money. The system cost declines are seen in future cost streams and are thus affected more by the customer discount rate.

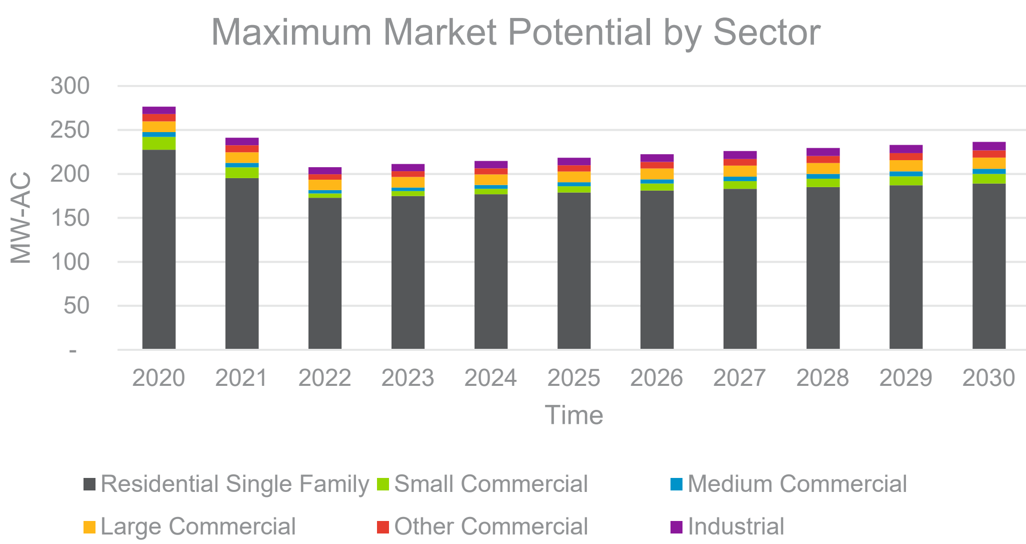

Figure 12. Distributed Solar PV Maximum Market Potential in DESC by Sector

4.3 Market Potential

Market Potential reflects the realistic adoption trajectory of a technology, given technical, eligibility, customer willingness to adopt, and awareness. Combined forecast and historical plots for cumulative installed capacity are shown by sector in the calibration section (Section 3.5). Where not explicitly noted, all figures refer to the “Mid-Cost” Scenario.

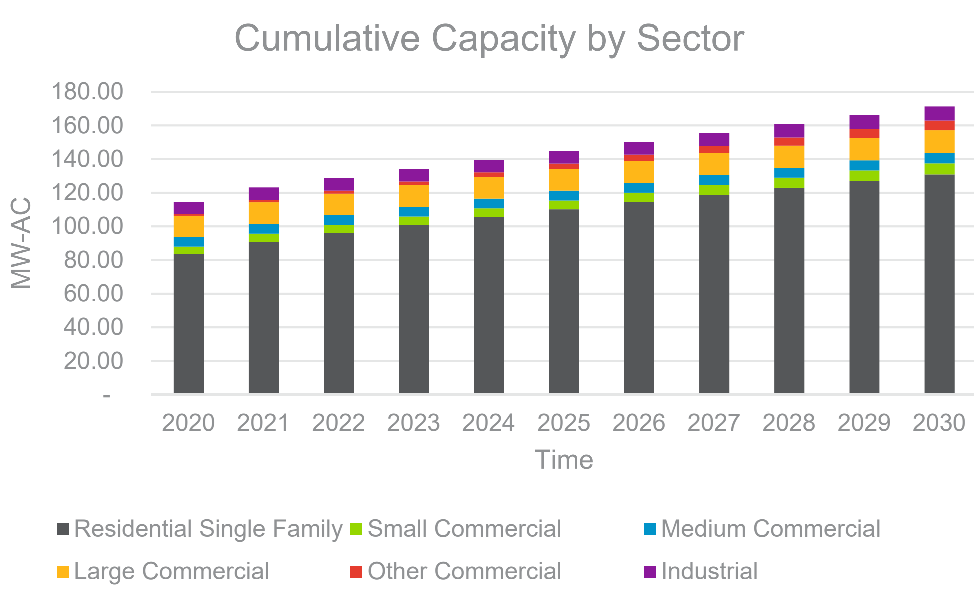

Figure 13. Distributed Solar PV Cumulative Market Potential in DESC by Sector

Although the Solar PV market in DESC territory appears to be reaching a more mature phase (see Figure 8) due in part to early movers having already adopted solar PV and the ITC sunset, the study shows that there is still room for distributed solar PV growth as favorable policies like net energy metering and the state tax credit drive the long run market share up as costs continue to decline. Figure 13 shows the combined projected installed capacity for all sectors. This figure shows the “Mid-Cost” scenario, characterized by slow growth with around 6 MW AC added per year. Though residential adoption still makes up the majority of the market potential, growth is also seen in commercial sectors, particularly Other Commercial.

In the next sections, we examine Market potential for the "Mid-Cost" scenario in the context of Technical, Eligible, and Maximum Market potential for each sector. Please note that some figures use a log scale on the Y-axis due to the large differences between potentials.

4.3.1 Residential Market Potential

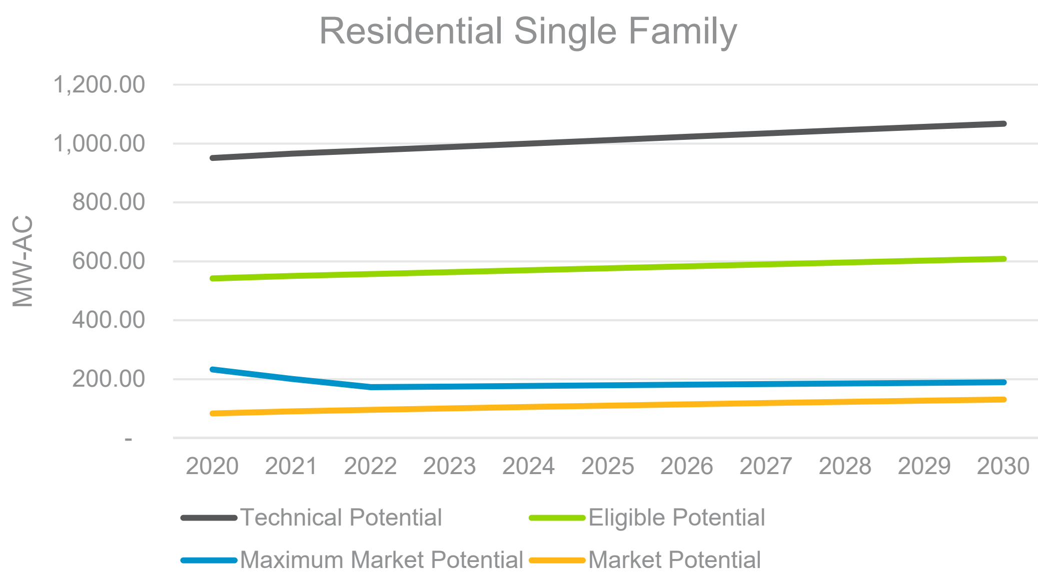

Figure 14. Technical, Eligible, Maximum Market, and Market Potential for the Residential Single-Family Sector

In the "Mid-Cost" scenario, the sunset of the ITC for residential customers has a large impact on the economics of Solar PV ownership. This impact is seen in the forecast of Maximum Market potential in Figure 14. Because the Maximum Market potential is effectively a dynamic asymptote for the Market potential, the growth of the Market potential slows though 2021 and then re-stabilizes relative to the lower asymptote reflecting the reduced bill savings that customers experience without the ITC credit.

4.3.2 Small Commercial Market Potential

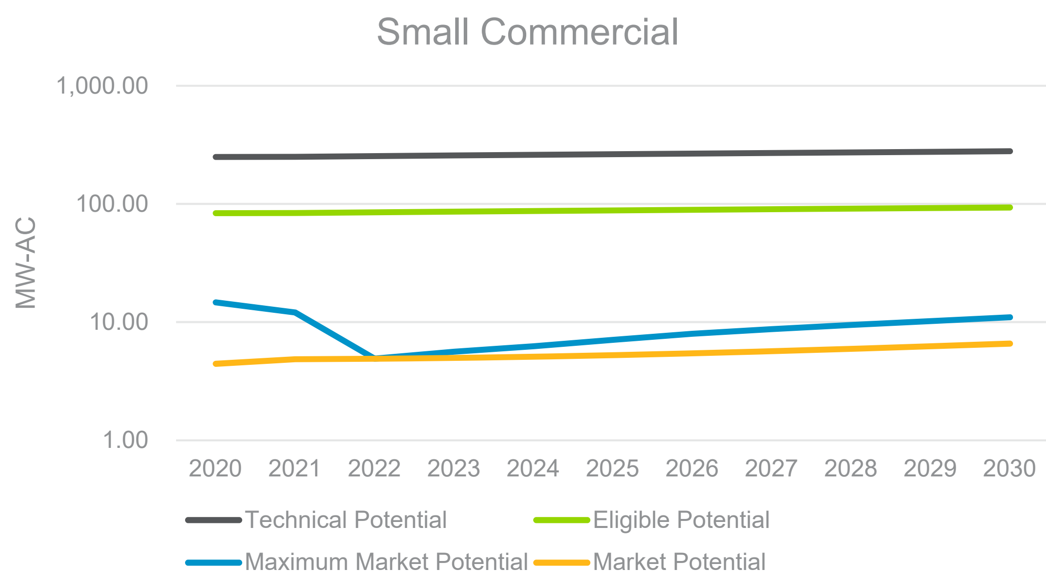

Figure 15. Technical, Eligible, Maximum Market, and Market Potential for the Small Commercial Sector. Y-Axis in Log Scale

Small Commercial customers are forecasted to experience lower relative bill savings than residential customers in the years preceding the ITC sunset in the “Mid-Cost” scenario, but are forecasted to achieve greater savings afterward due in part to the remaining 10% federal tax credit for commercial systems coupled with favorable rates.[27] However, typical of small commercial customers, there is a lower willingness to adopt overall, and calibration results suggest the market is closer to the long run market share (Figure 9).These factors drive the market potential for this segment lower.

[27] Most small commercial customers are on rate 9, which has a mild TOU and a small demand change, which only applies to the summer season.

4.3.3 Medium Commercial Market Potential

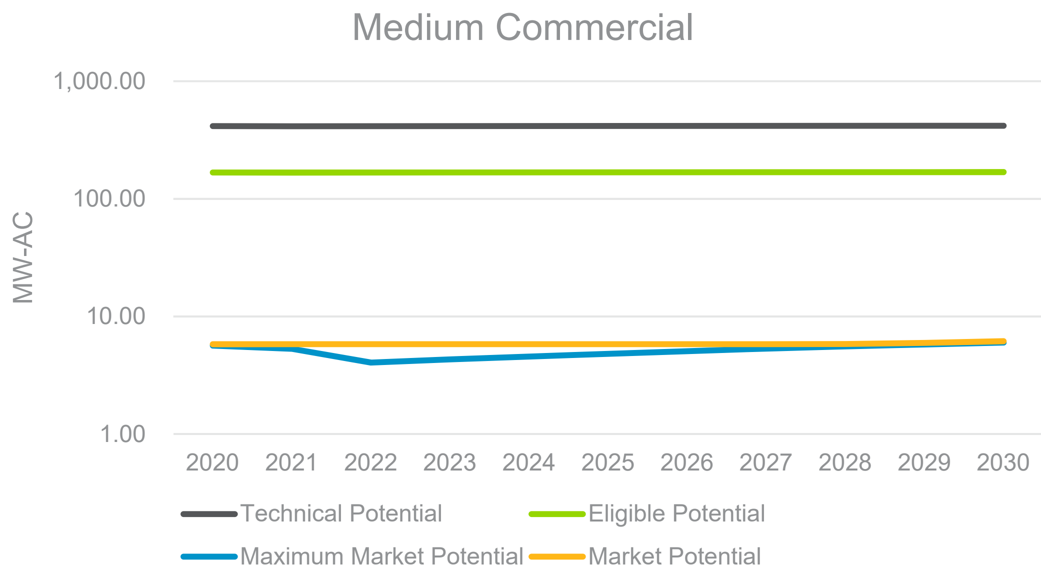

Figure 16. Technical, Eligible, Maximum Market, and Market Potential for the Medium Commercial Sector. Y-Axis in Log Scale

Incremental installation in the Medium Commercial sector is expected to continue in the “Mid-Cost” scenario but at low levels. The Maximum Market Potential for this sector is quite low, and the sector is close to the long run market share, as shown in Figure 9 and Figure 16. Installations have dropped sharply since their height in 2016. Rates with a strong demand component[28] contribute to negative bill savings for this sector on average, meaning that the typical customer would see a net increase in their monthly energy costs. This is exacerbated by the ITC sunset to 10% after 2021 in the “Mid-Cost” scenario.

[28] Most medium commercial customers are on rate 20, which has a relatively large demand change.

4.3.4 Large Commercial Market Potential

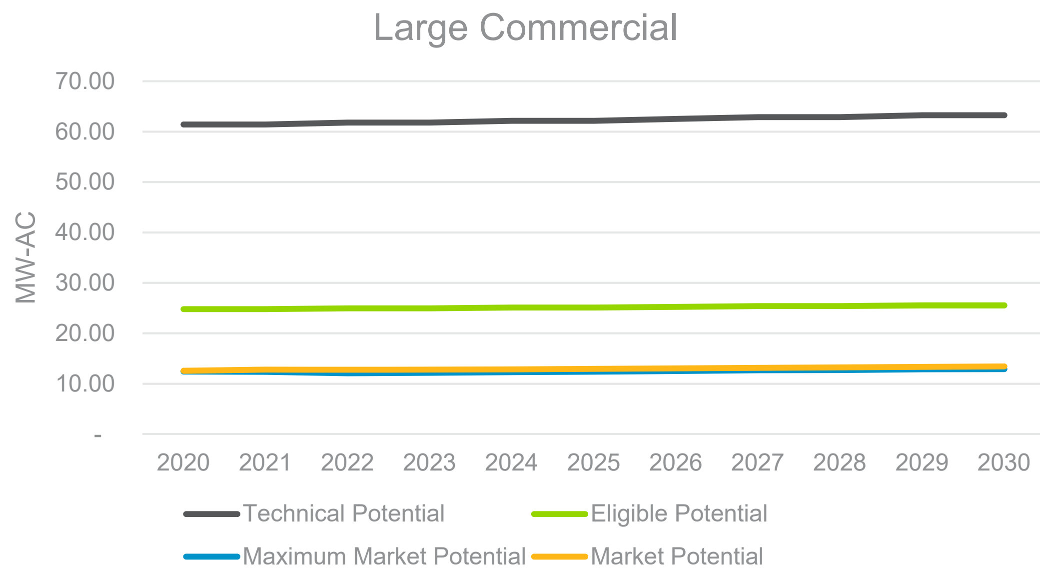

Figure 17. Technical, Eligible, Maximum Market, and Market Potential for the Large Commercial Sector

Similar to Medium Commercial, Guidehouse forecasts that Large Commercial installations will continue in the "Mid-Cost" scenario but at very low levels in the near future as shown in Figure 18. This is due to the market potential pushing up against the long run market share and the ITC sunset. The study forecasts that installations begin to increase in the late 2020s as declining costs improve the economics and expand the Long-run Market potential.

4.3.5 Other Commercial Market Potential

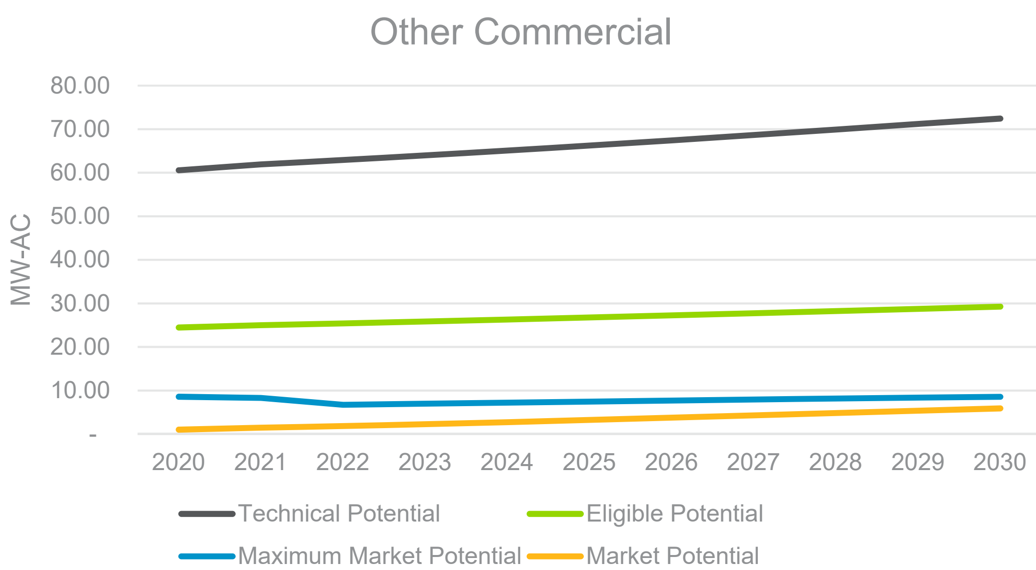

Figure 18. Technical, Eligible, Maximum Market, and Market Potential for the Other Commercial Sector

Guidehouse expects sustained growth in installations in the Other Commercial sector in the "Mid-Cost" scenario, as seen in Figure 18. This sector is composed primarily of schools, farms, municipal, and church customers which tend to have higher propensity to adopt solar as well as favorable bill ratios. On average, Other Commercial customers are modeled to have the highest bill savings of the commercial sectors analyzed, due to volumetric based rates, which are favorable to solar PV.[29] However, it should also be noted that due to the small sample size of customers in the interconnection data (see Figure 9), there is some uncertainty about the determination of the Long Run Market share for this sector. This is discussed further in Section 3.5.

[29] The majority of Other Commercial customers are split between rates 12, 14, and 22, all of which are energy-based.

4.3.6 Industrial Market Potential

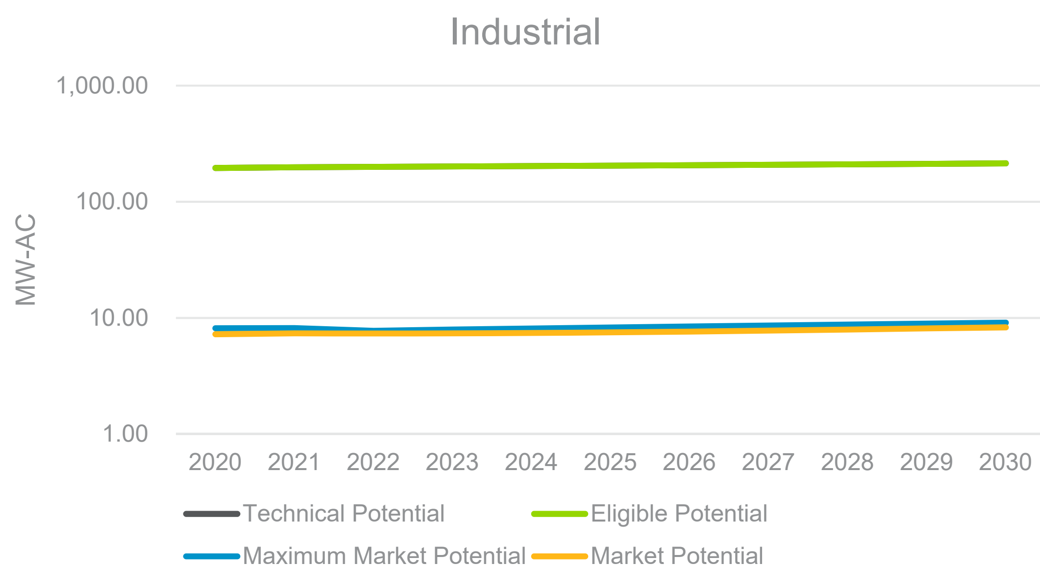

Figure 19. Technical, Eligible, Maximum Market, and Market Potential for the Industrial Sector. Y-Axis in Log Scale

In the "Mid-Cost" scenario, the Industrial sector forecast shows slow but steady growth, limited by the small and mature market, as shown in Figure 19. Incremental installed capacity for Industrial has been dropping since 2018. Industrial customers have a large demand component on their bill,[30] which contributes to the slightly negative bill savings modeled for these customers over the entire forecast horizon in the “Mid-Cost” scenario.

4.4 Scenario Analysis

In this section we present Market potential for each sector by scenario. Scenario descriptions are available in Section 3.3, and include cost and policy drivers. The single largest effect is the simulation of the ITC extension for all customers in 2021 in the “Low-Cost” scenario. All figures in this section are in cumulative MW AC.

[30] The majority of Industrial customer are on rate 23, which has a relatively large demand charge.

4.4.1 Residential Market Scenarios

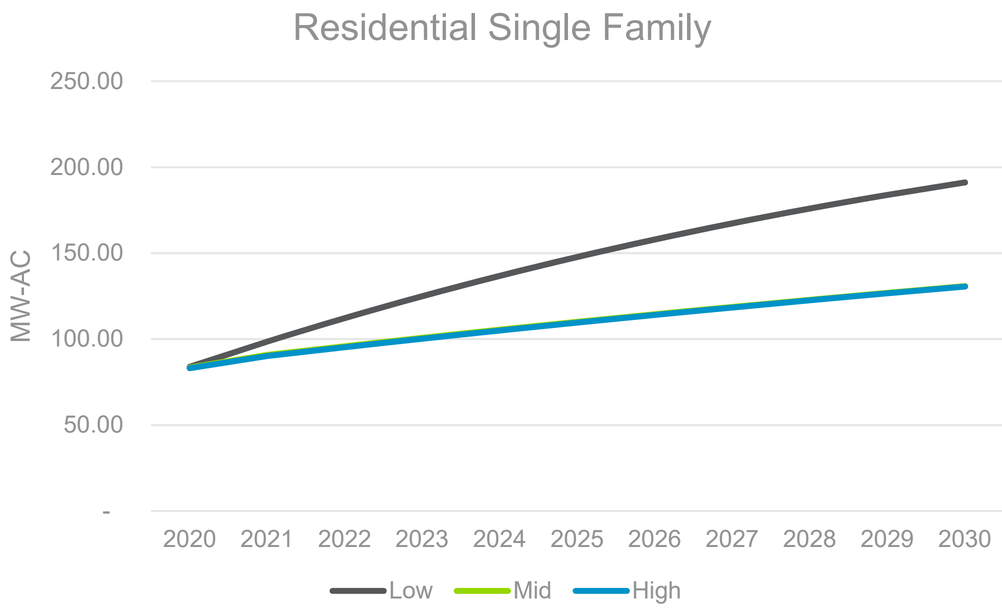

Figure 20. Cumulative Market Potential for Residential Single-Family by Scenario

Slow, but sustained growth in installed capacity is expected for the Residential Single-Family sector due to favorable economics and increasing awareness of Solar PV. In the "Low-Cost" scenario, the market is buoyed by the ITC extension and capacity additions remain near 2020 levels. Overall, the difference in total installed capacity by 2030 between scenarios is forecasted to be approximately 61 MW AC. Only a very small difference (less than 1 MW) is expected for residential customers between the "Mid" and "High" scenarios.

4.4.2 Small Commercial Market Scenarios

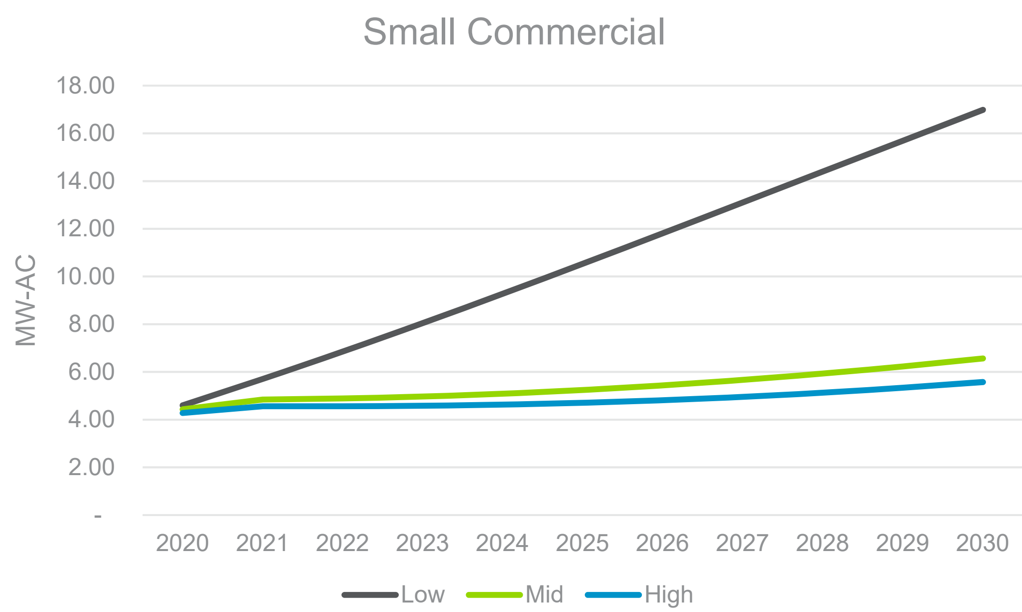

Figure 21. Cumulative Market Potential for Small Commercial by Scenario

Relative to forecasted installed capacity in Residential Single-Family, the Small Commercial sector is a small market. However, even in the "High-Cost" scenario Guidehouse expects slow growth. In the "Low-Cost" scenario, the extension of the ITC at 30% creates headroom for more rapid growth, with about 12 MW-AC added during the forecast horizon. The observed range in installed MW for small commercial between the scenarios was about 10 MW-AC.

4.4.3 Medium Commercial Market Scenarios

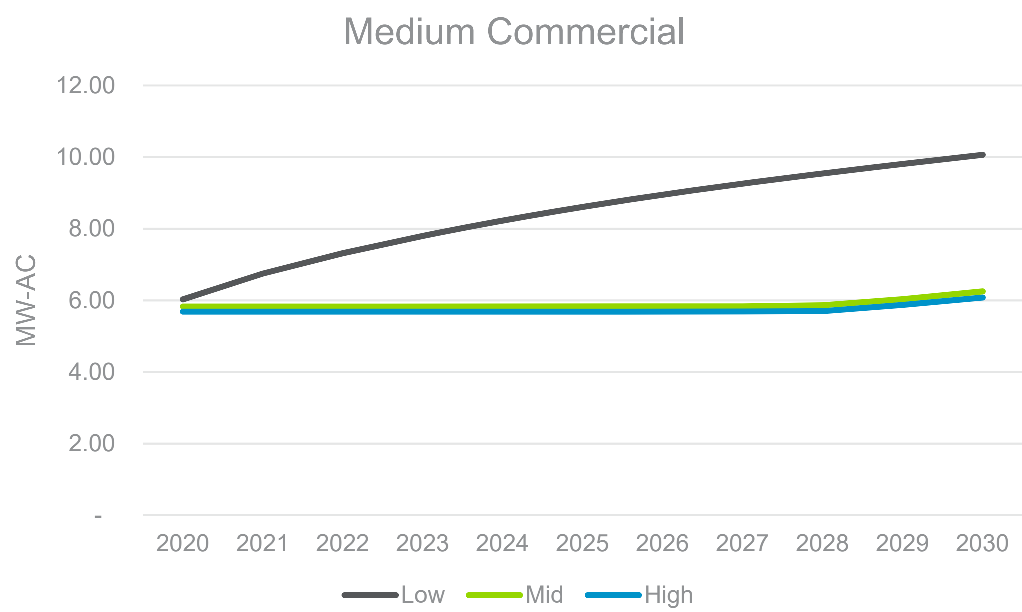

Figure 22. Cumulative Market Potential for Medium Commercial by Scenario

In the Medium Commercial sector growth is expected to be minimal in all but the “Low-Cost” scenario (Figure 22). Reasons for this are discussed in Section 4.3. Even in the “Low-Cost” scenario, growth slows as market saturation increases. Because the market was slowing down even when the full tax incentives were in place (30% ITC + 25% South Carolina state tax credit), the ITC extension provides only a limited increase from about 6 MW installed in 2030 (“Mid” and “High”) to about 10 MW in the “Low-Cost” case.

4.4.4 Large Commercial Market Scenarios

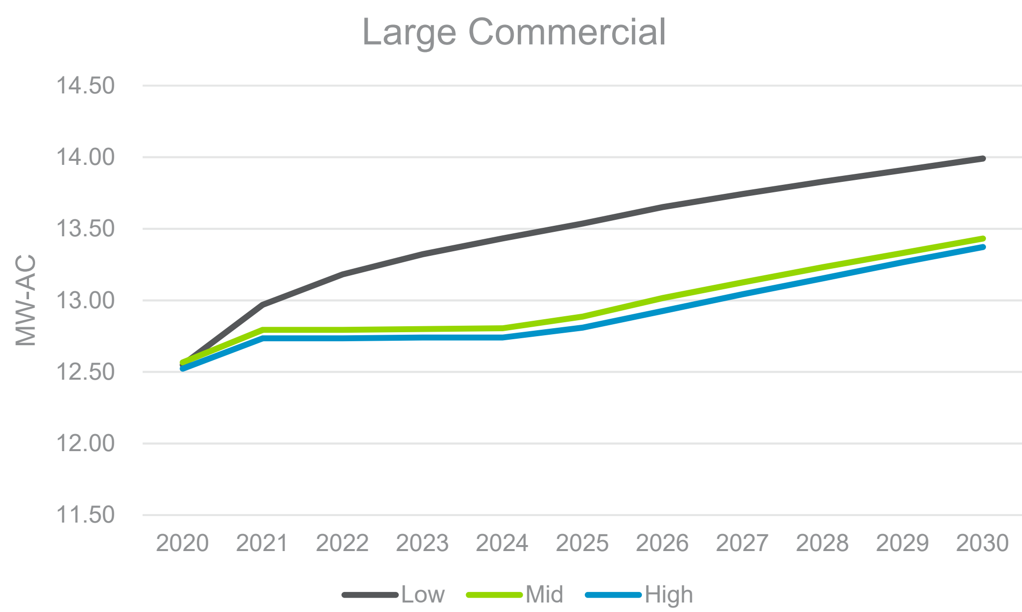

Figure 23. Cumulative Market Potential for Large Commercial by Scenario

Slow growth is also expected in the Large Commercial sector for all scenarios, as shown in Figure 23. The effect on the ITC is seen in years 2021-2024, as in the “Mid-Cost” and “High-Cost” the credit is expected to ramp down to 10%. This creates a period where the market is suppressed until cost declines bring the long run market potential back above the market potential and growth continues. In the “Low-Cost” scenario, the ITC extension prevents this lull. The observed range in installed MW for Large Commercial between the scenarios was only about 0.5 MW-AC.

4.4.5 Other Commercial Market Scenarios

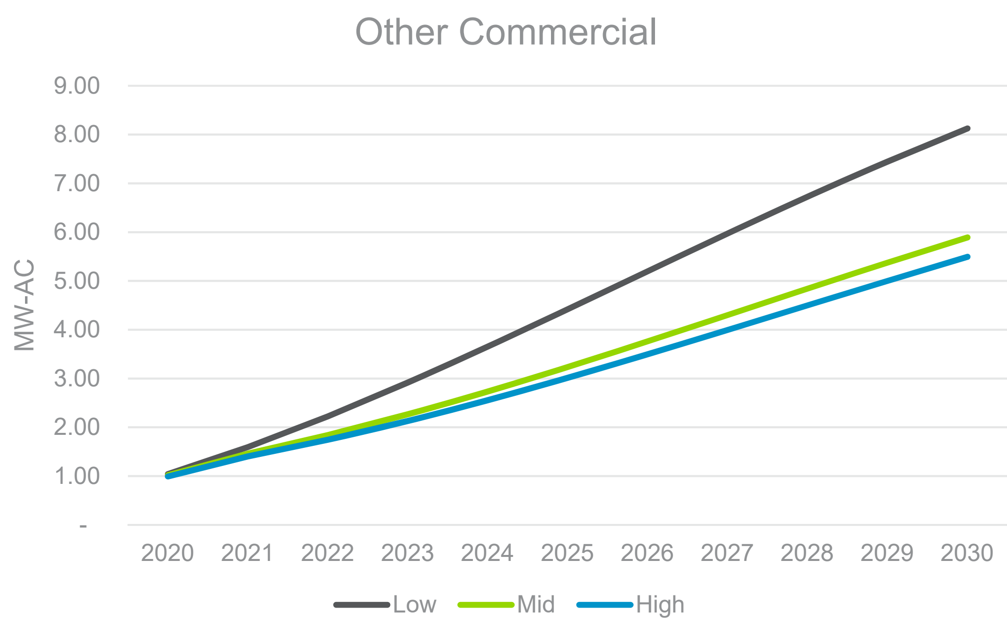

Figure 24. Cumulative Market Potential for Other Commercial by Scenario

As mentioned in Section 4.3, the Other Commercial sector shows potential for continuing growth despite low historical installed capacity. As shown in Figure 24, this is true for all scenarios. In the “Mid-Cost” and “High-Cost” scenarios, capacity increases by about 5 MW AC, whereas in the “Low-Cost” scenario, capacity increases by about 7.5 MW AC.

4.4.6 Industrial Market Scenarios

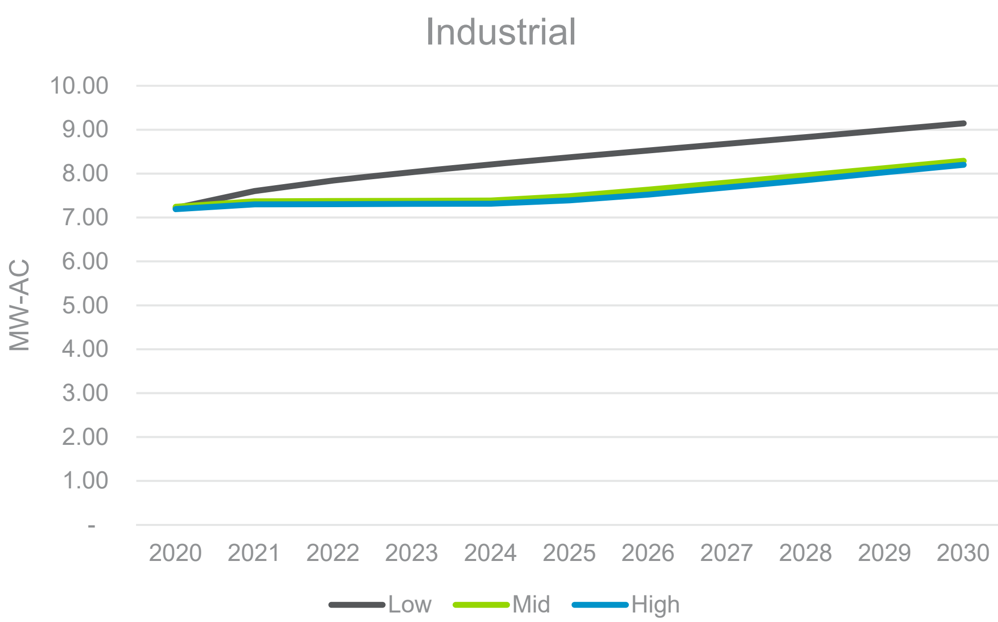

Figure 25. Cumulative Market Potential for Industrial by Scenario

Like Medium and Large Commercial growth in the Industrial sector is slow and fairly consistent, excepting the years immediately after the ITC sunset (“Mid” and “High”). Overall, the range in installed capacity between the scenarios is around 1 MW AC, reflecting the marginal economics of Solar PV for the Industrial Sector regardless of tax incentives. For the average industrial customer, demand-based rates make bills savings though Solar PV difficult due to intermittency, limiting the market to special cases and adoption driven by non-economic factors.

5. Conclusions

In the DESC territory, the “Mid-Cost” scenario shows solar PV growth to continuing at lower levels though 2030 due to market maturity and the sunset of the federal ITC which lowers the long run equilibrium market share. The “Low-Cost” scenario also shows growth, but at higher levels.

5.1 Conclusions: Commercial and Industrial

In Commercial and Industrial sectors slowing growth could already be observed in 2018 when full incentives were available. This suggests the maturity of the limited and more “niche” markets in these sectors. For Medium, Large, and Industrial, the less attractive economics of solar PV is driven by the fundamentals of demand-based rates, limiting the market to customers that are not driven exclusively by opportunities for bill savings. The Small Commercial and Other Commercial sectors do show higher potential for growth, especially in the “Low-Cost” scenario. The Other Commercial sector contains customers like schools, churches, and municipal buildings, that may have social or policy goals as well as motivation from more attractive economics. Small Commercial adoption can be challenging, as these customers can be hard to reach for installers, marketers, and other market actors.

Market potential growth is relative to the Long Run Market potential, and thus depends somewhat on customer preference in addition to economic factors. Customer preference can shift over time due to social norms, marketing, and perception of externalities. Because of this, when considering the market size, it is important to keep in mind Technical and Eligible Potential (Section 4.1). Though an exploration of market barriers is outside the scope of this study, Technical and Economic potential for commercial and industrial customers segments is quite large, suggestive of future untapped potential.

5.2 Conclusions: Residential

Slow sustained growth in the Residential sector accounts for the majority of the forecast Solar PV adoption in DESC territory under all studied scenarios and despite a 0% federal ITC in both the “Mid-Cost” and “High-Cost” scenarios. This growth is expected to be lower in out-years (about half the annual installed capacity expected in 2020) as the ITC sunset reduces the expected average monthly bill savings and thus the long run equilibrium market share. The importance of the ITC to residential markets is demonstrated in the “Low-Cost” scenario, where annual installed capacity remains at or above 2020 levels though the late 2020’s. The outsized impact of the ITC is due to economic affect that an upfront rebate can have on customers relative to future debt payments. After the initial shock of the expected sunset in the “Mid-Cost” scenario, our forecast suggests that markets will stabilize. Residential installed capacity will continue to grow though the study period as costs decline, awareness increases, and new customers enter the market.